Legislation and Regulations

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Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2001* (*AEO2001*) are based on Federal, State, and local laws and regulations in effect on July 1, 2000. The potential impacts of pending or proposed legislation, regulations, and standards—and sections of existing legislation for which funds have not been appropriated—are not reflected in the projections.

Federal legislation incorporated in the projections includes the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents per gallon to the Federal tax on highway fuels [*1*]; the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; the Tax Payer Relief Act of 1997; the Federal Highway Bill of 1998, which includes an extension of the ethanol tax incentive; and the new standards for the sulfur content of motor gasoline. *AEO2001* assumes the continuation of the ethanol tax incentive through 2020. *AEO2001* also assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 will increase with inflation and that Federal taxes on those fuels will continue at 1999 levels in nominal terms. Although the above tax and tax incentive provisions include “sunset” clauses that limit their duration, they have been extended historically, and *AEO2001* assumes their continuation throughout the forecast.

AEO2001 also incorporates regulatory actions of the Federal Energy Regulatory Commission (FERC), including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets, and other FERC actions to foster more efficient natural gas markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted. As of July 1, 2000, 24 States and the District of Columbia had passed legislation or promulgated regulations to restructure their electricity markets.

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, there is a phased reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although “banking” of allowances from earlier years is permitted. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NO_x) emissions; the forecast includes NO_x caps for States where they have been finalized, as discussed later in this section. The impacts of CAAA90 on electricity generators are discussed in “Market Trends” (see page 99).

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided, including the refrigerator standard that goes into effect in July 2001 and the standard for fluorescent lamp ballasts that goes into effect in April 2005. A discussion of the status of efficiency standards is included later in this section.

Energy combustion is the primary source of anthropogenic (human-caused) carbon dioxide emissions. *AEO2001* estimates of emissions do not include emissions from activities other than fuel combustion, such as landfills and agriculture, nor do they take into account sinks that absorb carbon dioxide, such as forests.

The *AEO2001* reference case projections include analysis of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. CCAP was formulated as a result of the Framework Convention on Climate Change, which was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992. As part of the Framework Convention, the economically developed signatories, including the United States, agreed to take voluntary actions to reduce emissions to 1990 levels. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the analysis.

Although CCAP no longer exists as a unified program, most of the individual programs, which are generally voluntary, remain. The impacts of those programs are included in the projections. The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto

Protocol, which was agreed to on December 11, 1997, but has not been ratified, or other international agreements (see "Issues in Focus," page 51, for further discussion of carbon dioxide emissions and the Kyoto Protocol).

Nitrogen Oxide Emission Caps

On September 24, 1998, the EPA promulgated rules to limit NO_x emissions in 22 eastern and midwestern States. The rules, commonly referred as the "NO_x SIP Call," called for capping summer season—May through September—power plant NO_x emissions beginning in 2004. The rules were initially represented with the proposed emissions budgets in the *Annual Energy Outlook* beginning in 1999; however, several industry groups challenged the regulations, and the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an order preventing EPA from implementing them. Consequently, the rules were not represented in *AEO2000*.

On March 3, 2000, the D.C. Circuit issued an order upholding the SIP Call with minor revisions—removing facilities in the State of Wisconsin from the program and asking EPA to review the requirements for facilities in Georgia and Missouri. As a result, *AEO2001* represents the provisions of the SIP Call for the 19 States where the NO_x caps have been finalized. The SIP Call is represented as a cap and trade program under which individual companies can choose to comply by reducing their own emissions or by purchasing allowances from other companies that have more than they need. The specific limits for each State are given in Table 2.

Table 2. Summer season NO_x emissions budgets for 2003 and beyond (thousand tons per season)

State	Emissions cap
Alabama	30.60
Connecticut	5.20
Delaware	5.00
District of Columbia	0.20
Illinois	36.60
Indiana	51.80
Kentucky	38.80
Maryland	13.00
Massachusetts	14.70
Michigan	29.50
New Jersey	8.20
New York	31.20
North Carolina	32.70
Ohio	51.50
Pennsylvania	46.00
Rhode Island	1.60
South Carolina	19.80
Tennessee	26.20
Virginia	21.00
West Virginia	24.05

FERC Order 2000

Throughout the 1990s, the FERC has taken steps to bring competition to wholesale electricity markets. It has attempted to open access to the interstate electricity transmission system to all market participants. In 1996, FERC issued Orders 888 and 889, requiring transmission-owning utilities to make their facilities available to others under the same prices, terms, and conditions they charge themselves. They were also required to develop information systems to provide real-time data on the amount of transmission capacity they had available at any given point in time and the prices, terms, and conditions for using it.

In 1999, the FERC continued its efforts with the issuance of Order 2000, referred to as the "Regional Transmission Organizations (RTO) Order," on December 20, 1999 [*2*]. The FERC has come to believe that many of the operational and reliability issues now facing the electricity industry can best be addressed by regional institutions rather than by individual utilities operating their own systems. As stated by the FERC, "Appropriate regional transmission institutions could: (1) improve efficiencies in transmission and grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation" [*3*]. As a result, Order 2000 requires that transmission-owning utilities file a proposal for an RTO by October 15, 2000, and have the RTO operating by December 15, 2001.

The FERC has not attempted to define what the appropriate regions are, how many RTOs there should be, or how they should be organized. The details are left to the utilities to propose. Essentially, Order 2000 goes a step beyond the open access provisions of Orders 888 and 889, requiring utilities to put their transmission systems under the control of independent regional institutions.

Although the FERC plans to allow utilities considerable flexibility in their RTO proposals, it has specified certain key functions that an RTO must provide, including tariff administration and design, congestion management, parallel path flow, provision of ancillary services, real-time information on total transmission and available transmission capability, market monitoring, transmission system planning and expansion, and interregional coordination. Essentially, the RTO is responsible for planning, operating, and monitoring the transmission system under its control. It is to operate independently of the transmission-owning utilities and ensure that all market participants have equal access to the services of the transmission system. At this time, the future regional organization of the wholesale electricity market is unclear.

Updates on State Renewable Portfolio Standards and Renewable Energy Mandates

Environmental and other interests have spurred the introduction of 10 State-level renewable portfolio standard (RPS) programs, as well as other mandates to build new electricity generating capacity powered by renewable energy [*4*]. The 10 States identified as having renewable portfolio standards are Arizona, Connecticut, Maine, Massachusetts, Nevada, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin. The State RPS programs vary widely in specifics, but all require that increasing percentages of the State's electricity supply be provided from a menu of eligible renewable energy resources. The mandates also vary in detail, but all tend to identify the technologies to be used and the amounts of capacity to be built.

Texas and New Jersey account for the two largest blocks of new renewable energy generating capacity projected to result from RPS programs in *AEO2001*. The Texas RPS specifies that 2,000 megawatts of new renewable energy generating capacity be built in Texas by 2009, with increasing interim requirements and individual utilities' shares assigned in proportion to their retail sales. Utilities may generate the power themselves or purchase credits from others with surplus qualifying generation; production from some existing facilities can also contribute to reducing a utility's requirements. Although the Texas RPS includes biomass, geothermal, hydroelectricity, and solar energy technologies, wind and landfill gas are expected to provide most of the new capacity to meet the RPS. Large new wind facilities already have been announced or contracted in response to the program.

New Jersey's RPS specifies increasing percentages of sales, such that 4 percent of each New Jersey retail electricity provider's sales are to be supplied by renewables (excluding hydroelectric) by 2012. Qualifying generating units located outside New Jersey may contribute to the renewables share, and a trading program is being developed. Biomass and landfill gas are expected to be the primary renewables used to meet New Jersey's RPS, along with some new wind capacity. Estimates for new generating capacity under the RPS are included in *AEO2001*.

California imposes a non-RPS form of renewable energy mandate, using a funding requirement under Assembly Bill 1890 (A.B. 1890) to collect $162 million from ratepayers of investor-owned utilities. Voluntarily proposed renewable energy projects bid competitively for support on a per-kilowatthour incentive basis. Winning capacity in the A.B. 1890 process is expected to include primarily wind, geothermal, and landfill gas projects. In August 2000, California extended the A.B. 1890 mandate, including additional funding. Specifics of a revised implementation plan are expected in early 2001. Estimates for new generating capacity under the original A.B. 1890 are included in *AEO2001*, but because no specifics are available, *AEO2001* does not include estimates for additional new capacity that would result from the August extension.

FERC Order 637

On February 9, 2000, the FERC issued Order 637, which modified the pricing rules for interstate natural gas pipeline services, primarily for short-term services in the secondary market. The Order is intended to allow capacity to be allocated more efficiently during peak periods to those who need it most. Before Order 637, short-term released capacity was subject to a price cap. When the value of the excess held capacity exceeded the price cap, there was no incentive for capacity holders to release the capacity. As a result, the unused capacity was often bundled with gas sales so that it could be sold by marketers at prices that were effectively above the cap, making it difficult for customers who needed additional capacity during peak periods to obtain it. Order 637 waives price ceilings for short-term (less than 1 year) released capacity for a trial period that will end on September 30, 2002. It is anticipated that this will make it much easier for those needing capacity to obtain it directly from holders of firm capacity.

Order 637 also allows pipelines to file for peak/off-peak and term-differentiated rate structures. The increase in revenue recovery from short-term peak period customers paying peak rates will reduce the cost recovery needed from long-term customers paying off-peak rates. The term-differentiated rates will be cost-based rates that, in the aggregate, will meet the annual revenue requirements of pipeline operators. The new rate structures, which are intended to better allocate economic risks, can apply either to long-term services alone or to both long- and short-term services.

Additional changes in regulations contained in Order 637 (1) encourage the increased use of auctions for available capacity by laying down basic principles and guidelines; (2) require pipelines to modify scheduling procedures so that released capacity can be scheduled on a basis comparable with other pipeline services; (3) permit shippers to segment capacity for more efficient capacity release transactions; (4) provide shippers more information on imbalances and services that can be used to avoid imbalance penalties; (5) implement penalties only to the extent necessary to ensure system reliability, with the revenues from such penalties credited to shippers; (6) narrow the right of first refusal to remove economic biases that existed previously; and (7) improve the FERC's reporting requirements to provide more transparent pricing information and permit more effective monitoring of the market. All the changes are intended to improve the competitiveness and efficiency of the interstate pipeline system.

Royalty Rules

Deepwater Royalty Relief

The Deep Water Royalty Relief Act was enacted in 1995 as an incentive for exploration and development of the deep waters of the Gulf of Mexico. The Act contains a mandatory provision, set to expire on November 28, 2000, that requires the Minerals Management Service (MMS) to offer leases with suspended royalties on volumes from certain portions of the deepwater Gulf of Mexico. Another provision, which does not expire, gives the MMS authority to include royalty suspensions as a financial feature of leases sold in the future. In September 2000 the MMS, acting under this authority, issued a set of proposed rules and regulations that provide a framework for continuing deepwater royalty relief on a lease-by-lease basis.

The mandatory provision of the Act provides royalty relief by eliminating royalties for deepwater leases according to a schedule based on both the volumes produced and the depth of the water: 17.5 million barrels oil equivalent for fields in 200 to 400 meters of water, 52.5 million barrels oil equivalent for fields in 400 to 800 meters, and 87.5 million barrels oil equivalent for fields in more than 800 meters. Leasing in the deepwater Gulf increased dramatically after the start of the royalty relief program, more than tripling between 1995 and 1997. Although it has fallen off from the 1997 peak, the levels remain considerably above those seen before the program, and the program has been deemed a success by the MMS and by the industry.

Hoping to enhance the positive effects of the program, the MMS has in the proposed new rules and regulations modified certain provisions to provide increased flexibility. Under the new rules, volumes will be assigned to individual leases rather than to fields, with volumes and depths specified at the time of the lease sale.

Royalty in Kind

Since the August 1996 enactment of the Federal Oil and Gas Royalty Simplification and Fairness Act, the MMS has been evaluating more extensive use of royalty in kind—the acceptance of a portion of oil or gas produced in lieu of cash to satisfy royalties. Benefits of accepting royalty in kind payments could include a reduced administrative burden for both industry and the MMS, fewer disputes over royalty determinations, more accurate royalty determinations, and maximization of Government revenues from royalties.

In addition to the Small Refiners Program, which was initiated in the 1970s to give small refiners access to crude oil at fair prices through the sale of royalty oil, and a more recent program (completed in October 2000) to add 28 million barrels of royalty oil to the Strategic Petroleum Reserve, four pilot projects are being used to assess the feasibility of royalty in kind. The first project, initiated in 1998 for onshore crude oil from Federal leases in the Powder River and Big Horn basins in Wyoming, has moved to operational status. A second 1998 project involves natural gas from leases in the Texas 8(g) zone of the Gulf of Mexico. A more comprehensive 1999 project, which includes natural gas from Federal leases in the entire Gulf of Mexico, allows a portion of the gas that would otherwise be sold competitively on the open market to be transferred to the Government Services Administration (GSA) for use in Government facilities. A fourth pilot project, initiated in 2000, applies to crude oil from Federal leases in the Gulf of Mexico.

The FERC has claimed that the method used to transfer gas to GSA under the third project, conflicts with its open-access policies by potentially circumventing the competitive bidding requirements for securing pipeline capacity. The FERC has granted MMS a waiver until October 31, 2001, so that the program can continue but has insisted that MMS develop a plan by August 2001 to either replace the auction system or contract for its own firm transportation capacity so that the program will conform with FERC policy.

Crude Oil Valuation

On March 15, 2000, the MMS published the final rule for the valuing of crude oil produced on Federal lands for the purpose of determining royalty payments. The rule took effect on June 1, 2000, with a 3-month interest-free grace period to allow industry to make any changes needed to implement the rule. The rule is based on the premise that spot market pricing is the best indicator of the value of crude oil in today's market, and it applies spot market pricing for the major integrated companies and others that refine their oil. The use of spot market rather than posted prices would have increased Government revenues by nearly $67.3 million according to the MMS [*5*], with most of the additional revenues coming from the major integrated oil companies. Because of administrative savings associated with the new rule, MMS maintains that the net increase in costs to the industry will be an estimated $63.5 million. So as not to cause small independent producers undue hardship, they will be allowed to continue to value crude oil using posted prices as they did under the 1988 rule and, thus, will not be affected.

Tier 2 Vehicle Emissions and Gasoline Sulfur Standards

CAAA90 set "Tier 1" exhaust emissions standards for carbon monoxide (CO), hydrocarbons, NO_x, and particulate matter for light-duty vehicles and trucks beginning with model year 1994. CAAA90 also required EPA to study further "Tier 2" emissions standards that would take effect in model year 2004. EPA provided a Tier 2 study to Congress in July 1998, which concluded that tighter vehicle standards are needed to achieve attainment of National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter between 2007 and 2010.

In February 2000, EPA published its Final Rule on "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements [*6*]. The Final Rule includes standards that will significantly reduce the sulfur content of gasoline throughout the United States to ensure the effectiveness of emissions control technologies that will be needed to meet the Tier 2 emissions targets. The inclusion of the new Tier 2 standards and low-sulfur gasoline requirements in the *AEO2001* reference case is a noteworthy change from the *AEO2000* reference case.

In 2004, manufacturers must begin producing vehicles that are cleaner than those being sold today. The standards would also be extended to light-duty trucks, minivans, and sport utility vehicles (SUVs) which currently pollute three to five times more than cars. This is the first time that the same set of emissions standards will be applied to all passenger vehicles. In its Final Rule, EPA notes that the single set of standards is appropriate given the increasing use of light trucks for personal transportation and the increasing number of vehicle-miles traveled by light trucks. The same standards will be applied to vehicles operated on any fuel.

For passenger cars and light-duty trucks rated at less than 6,000 pounds gross vehicle weight, the standards will be phased in beginning in 2004, with full implementation by 2007. For light-duty trucks rated at more than 6,000 pounds gross vehicle weight and medium-duty passenger vehicles (a new class introduced by the rule to include SUVs and passenger vans rated between 8,500 and 10,000 pounds), the standards will be phased in beginning in 2008, with full implementation in 2009. Interim average standards will apply during the phase-in periods, which are from 2004 to 2007 for passenger cars and light-duty trucks less than 6,000 pounds and from 2004 to 2008 for light-duty trucks more than 6,000 pounds and medium-duty passenger vehicles.

Because automotive emissions are linked to the sulfur content of motor fuels, the Final Rule also requires a reduction in average gasoline sulfur levels nationwide. Sulfur reduces the effectiveness of the catalyst used in the emission control systems of advanced technology vehicles, increasing their emissions of hydrocarbons, CO, and NO_x. The sulfur content of gasoline must be reduced to an annual average of 30 parts per million (ppm), and a maximum 80 ppm in any gallon, to accommodate the new emissions control systems and meet the Tier 2 standards. The new Federal standard is equivalent to the current standard for gasoline in California at about one-fourth the sulfur content in areas currently using reformulated gasoline and about one-tenth the current sulfur content of conventional gasoline.

Because the standard will require refiners to invest in sulfur-removing processes, it will be phased in between 2004 and 2007 and, initially, will allow less stringent standards for small refiners. To encourage reductions before 2004, refiners will receive credits for sulfur reductions below a baseline level. The credits can be used later as "allotments," which will allow a refiner to exceed the new sulfur standard by a given amount. Gasoline produced by most refiners will be required to meet corporate average sulfur contents of 120 ppm in 2004 and 90 ppm in 2005. The corporate average will be phased out by 2006, when most refiners must meet a refinery-level average of 30 ppm. Refiners producing most of their gasoline for the Rocky Mountain region will also be allowed a more gradual phase-in because of less severe ozone pollution in the area; they will be required to meet a refinery average of 150 ppm in 2006 and must meet the 30 ppm requirement in 2007. Small refiners will not be required to meet the 30 ppm standard until 2008.

Heavy-Duty Vehicle Emissions and Diesel Fuel Quality Standards

In August 2000 the EPA finalized new regulations to reduce emissions from heavy-duty trucks and buses substantially. In the Final Rule, the standards for all diesel vehicles over 8,500 pounds will reduce NO_x emissions by more than 40 percent through reductions in hydrocarbons beginning in 2004 [*7*]. New test procedures and compliance requirements will begin in the 2007 model year, and on-board diagnostic systems will be required for engines in vehicles between 8,500 and 14,000 pounds, with a phase-in period covering the 2005 through 2007 model years [*8*]. New standards for heavy-duty gasoline engines and vehicles will reduce both hydrocarbons and NO_x for all vehicles above 8,500 pounds not covered in the Tier 2 standards, beginning in 2005. The rule also includes incentives for manufacturers to begin meeting the standards in 2003 or 2004. On-board diagnostic systems will also be required for heavy-duty gasoline vehicles and engines up to 14,000 pounds.

In order to enable diesel engine technology to meet tighter emissions standards, EPA has proposed new standards for diesel fuel quality, which would become effective in mid-2006. The proposed standards would cap diesel fuel sulfur content at 15 ppm from the current maximum standard of 500 ppm. In addition to reduced sulfur content, the standards would also maintain hydrocarbon emissions by continuing to require a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume [*9*]. EPA estimates that the proposed diesel standards would increase the cost of diesel fuel by 3 to 4 cents per gallon [*10*], although other estimates are higher. Because the proposed changes to diesel fuel standards have not been finalized, they are not included in the *AEO2001* reference case [*11*].

Banning or Reducing the Use of MTBE in Gasoline

Methyl tertiary butyl ether (MTBE) is a chemical compound used as a blending component in gasoline. Since 1979 it has been used to boost the octane of gasoline to prevent “engine knock.” The use of MTBE climbed in the 1990s, when it was used to meet Federal oxygen requirements for cleaner burning reformulated and oxygenated gasoline under CAAA90.

Despite the success of the CAAA90 gasoline programs in improving air quality, concerns about MTBE contamination of water supplies has led to a flurry of legislative and regulatory actions at the State and Federal levels that would either ban or limit the use of MTBE in gasoline. MTBE is the most commonly used “oxygenate” or oxygen booster, used in about 87 percent of reformulated gasoline (RFG); however, CAAA90 does not specify what type of oxygenate should be blended into gasoline. Some refiners, especially those in the Midwest, use ethanol as an oxygenate. Because a ban on MTBE would affect the economics and chemical characteristics of gasoline supplies, the issue has often been tied to proposals to waive the Federal oxygen requirement and to impose a new “renewable standard” that would, in effect, require a certain annual average percentage of ethanol to be blended into gasoline.

The *AEO2001* reference case reflects only changes to legislation or regulations that have been finalized and not those that are proposed. Therefore, the *AEO2001* projections incorporate MTBE bans or reductions in the States where they have passed but do not include any proposed State or Federal actions or the proposed oxygen waiver. Discussion of an alternative case which assumes that all States will ban MTBE is provided in “Issues in Focus” (page 35).

Water contamination by MTBE results primarily from leaking pipelines or gasoline storage tanks. MTBE moves through soil more easily than other gasoline components, and it is difficult and expensive to remove from groundwater. The issue of MTBE contamination of water supplies first captured public attention in 1996, when MTBE was detected in two wells representing half the drinking water supplies in Santa Monica, California. Since that time, a growing number of studies have detected MTBE in drinking water supplies throughout the country. Although about 99 percent of the detections have been well below levels of health concern, the odor and taste of MTBE can make water undrinkable even at very low concentrations. MTBE is five times more likely to be found in water supplies in the areas of the country that use Federal RFG than in those that do not.

In response to rising concerns about MTBE-tainted water supplies, the EPA convened a “Blue Ribbon

Panel" (BRP) in early 1999 to assess the extent of the problem and make recommendations. In addition to tighter safeguards for water protection, the BRP recommended that the use of MTBE be substantially reduced. To ensure a cost-effective phasedown of MTBE, the BRP suggested that Congress waive the 2 percent oxygen requirement for RFG while EPA develops a mechanism to prevent the current air quality benefits of RFG from declining.

In March 2000, the EPA issued an Advanced Notice of Proposed Rulemaking that would regulate the use of MTBE in gasoline under the authority of the Toxic Substances Control Act, which gives EPA the authority to regulate chemical substances to prevent unreasonable risks to health or environment. The Advanced Notice is the initial document in a lengthy rulemaking process and does not provide details about how the use of MTBE might be regulated. Political pressure for a quick resolution to the MTBE water contamination problem has resulted in numerous legislative proposals in the U.S. Congress that would limit or ban MTBE. On September 7, 2000, the Senate Environment and Public Works Committee reported out a bill, but Congress has not yet passed legislation that would address the MTBE issue. Questions of legal authority and time-consuming analysis of air quality benefits have prevented the EPA from granting a waiver to the Federal oxygen requirement.

States have taken the lead in passing legislation related to MTBE. The first law was passed in 1999 in California, where water problems first appeared. In March 1999 California's governor, Gray Davis, initially announced that MTBE would be banned in gasoline in the State by 2003. At that time the California Energy Commission requested that EPA waive the Federal oxygen requirement for California gasoline, and California congressmen introduced bills in the U.S. Congress that would waive the requirement. As of October 2000 no regulatory or legislative action has been taken to waive the Federal oxygen requirement in California or in any other State. The EPA is currently assessing whether an alternative gasoline formulation that does not include oxygen can give similar emissions reductions. In 2000, seven other States—Arizona, Connecticut, Maine, Minnesota, Nebraska, New York, and South Dakota—passed legislation to ban or limit the use of MTBE within the next several years. Unlike in California, the majority of the recent legislation in other States has not been linked to a waiver request. Legislation has also been drafted, but not passed, in Colorado, Hawaii, Iowa, Michigan, and Nebraska. The Maryland, New Hampshire, and Virginia legislatures have also passed bills to study or test for MTBE contamination, and Illinois has passed a bill that would change labeling at the gasoline pump. *AEO2001* incorporates legislation to ban or limit MTBE in the eight States where it has been passed.

The patchwork quilt effect of individual State bans on MTBE will further complicate the gasoline supply and distribution system in the United States, which already handles more than 50 different types of gasoline as a result of State and Federal regulations and market demand for different octane grades [*12*]. One example is in the Northeast, where 65 percent of the gasoline supply is RFG. There is concern that by banning MTBE, New York and Connecticut have effectively created an island around New York City where RFG without MTBE is required. Areas with unique gasoline requirements are more vulnerable to supply disruptions and related price spikes.

Proposed Changes to RFG Oxygen Standard

In June 2000, the EPA published a notice of proposed rule making (NPRM) that would provide refiners with more flexibility for producing RFG. The NPRM would relax the summer volatile organic compound (VOC) compliance standard for ethanol-blended RFG and would also replace the current minimum of 1.5 percent by weight per gallon with an annual average oxygen requirement of 2.1 percent by weight. The change in regulations would make it easier for refiners to produce RFG, especially in the summertime, when VOC standards make it more difficult to produce RFG with ethanol because of its volatility. Under the proposed regulations a refiner using ethanol as an oxygenate could choose to blend no ethanol in the summertime but meet the 2.1-percent annual average oxygen requirement by blending ethanol at higher concentrations during the rest of the year. Such a change might ease some of the tightness in blending that contributed to the gasoline price spikes in the Midwest last spring and summer and might make it easier to meet a renewable fuels standard, which has been discussed as part of the MTBE ban issue [*13*]. Because the rule is not final, *AEO2001* does not incorporate the change to the RFG standard.

Proposed Limits on Benzene in Gasoline

In July 2000 the EPA proposed a rule that identifies 21 mobile source air toxics (MSATs) and would limit the amount of one of those air toxics, benzene, in gasoline [*14*]. CAAA90 includes provisions governing toxic emissions from stationary sources but does not include a list of pollutants that should be classified as motor vehicle toxics. The proposed list of MSATs released by EPA in July 2000 includes compounds that result from fuel combustion in vehicle engines, along with certain metal compounds and diesel exhaust. The list of MSATs includes common gasoline components such as MTBE and benzene.

The EPA proposal includes an evaluation of the ability of other Federal emissions control programs—such as RFG, Tier 2 and gasoline sulfur reductions, and the national low emission vehicles program (NLEV)—to reduce MSATs. Because the evaluation determined that additional measures would be required to control benzene, EPA proposed a maximum limit on the amount of benzene that could be added to gasoline starting in 2002. The proposed standards would require refiners to maintain the average level of benzene that they used in 1998-1999, and they are expected to result in "negligible additional costs" to refiners. Because the rule limiting benzene has not been finalized, it is not reflected in the *AEO2001* projections.

Low-Emission Vehicle Program

The Low-Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could opt in to the California program and achieve lower emissions levels than required by CAAA90. Both New York and Massachusetts chose to opt in to the LEVP, implementing the same mandates as California.

The LEVP was an emissions-based policy, setting sales mandates for three categories of low-emission vehicles according to their relative emissions of air pollutants: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The only vehicles certified as ZEVs by the California Air Resources Board (CARB) were dedicated electric vehicles [*15*].

The LEVP was originally scheduled to begin in 1998, with a requirement that 2 percent of the State's vehicle sales be ZEVs, increasing to 5 percent in 2001 and 10 percent in 2003. In California, however, the beginning of mandated ZEV sales was rolled back to 2003, because it was determined that ZEVs would not be commercially available in sufficient numbers or at sufficiently competitive cost to allow the targets to be met. In September 2000 CARB decided to maintain the 2003 mandated start of the LEVP rather than delay. In Massachusetts and New York, after several years of litigation, the Federal courts overturned the original LEVP mandates in favor of the same deferred schedule adopted by California. For *AEO2001*, Maine and Vermont have been added to the LEVP mandates, because they have adopted programs similar to those in California, Massachusetts, and New York. It is assumed that vehicle sales will meet these mandates.

On November 5, 1998, the CARB amended the original LEVP to include ZEV credits for advanced technology vehicles. According to the CARB, qualifying advanced technology vehicles must be capable of achieving "extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range" [*16*]. There are three components in calculating the ZEV credit, which vary by vehicle technology: (1) a baseline ZEV allowance, (2) a zero-emission vehicle-miles traveled (VMT) allowance, and (3) a low fuel-cycle emission allowance. Using advanced technology vehicles in place of ZEVs in order to comply with the LEVP mandates requires assessment of each vehicle characteristic relative to the three criteria.

The baseline ZEV allowance potentially can provide up to 0.2 credit if the advanced technology vehicle meets the following standards: (1) super-ultra-low-emission vehicle (SULEV) standards, which approximate the emissions from power plants associated with recharging electric vehicles; (2) on-board diagnostics (OBD) requirements for indicators on the dashboard that light up when vehicles are out of emissions compliance levels; (3) a 150,000-mile warranty on emission control equipment; and (4) evaporative emissions requirements in California, which prevent emissions during refueling.

The second criterion, the zero-emission VMT allowance, will allow a maximum 0.6 credit if the vehicle is capable of some all-electric operation (to a range of at least 20 miles) that is fueled by off-vehicle sources (i.e., no on-board fuel reformers), or if the vehicle has ZEV-like equipment on board, such as regenerative braking, advanced batteries, or an advanced electric drive train. An emission allowance was also made for vehicle fuels with low fuel-cycle emissions used in advanced technology vehicles. A maximum of 0.2 credit is provided for vehicles that use fuels which emit no more than 0.01 gram of nonmethane organic gases per mile, based on the grams per gallon and the fuel efficiency of the vehicle.

Overall, large-volume manufacturers can apply ZEV credits for advanced technology vehicles up to a maximum of 60 percent of the original 10-percent ZEV mandate. (The original ZEV mandate required that 100 percent of the 10 percent of all light-duty vehicle sales must be ZEVs—defined only as dedicated electric vehicles—beginning with the 2003 model year.) The remaining 40 percent of the mandated ZEV sales still must be electric vehicles or variants of fuel cell vehicles that have extremely low emissions, such as hydrogen fuel cell vehicles.

Appliance Efficiency Standards

Since 1988, the U.S. Department of Energy (DOE) has promulgated numerous efficiency standards requiring the manufacture of appliances that meet or exceed minimum levels of efficiency as set forth by DOE test procedures. In 1987, Congress passed the National Appliance Energy Conservation Act (NAECA), which permitted DOE to establish test procedures and efficiency standards for 13 consumer products. Under the auspices of NAECA, DOE is responsible for revising the test procedures and efficiency levels as technology and economic conditions evolve over time.

From 1988 to 1995, DOE established and revised efficiency standards almost on an annual basis, as shown in Table 3. In 1995, however, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from establishing any new standards. The moratorium caused a delay of several years, with no standards becoming effective from 1996 through July 2000. After a reevaluation of the standards program, DOE established a new process that allows for greater input from stakeholders by creating the Advisory Committee on Appliance Energy Efficiency Standards, which comprises technical experts representing the concerns of industry, environmentalists, and the general public.

With input from stakeholders early in the promulgation process, it was believed that the rulemaking process would become more predictable, more timely, and less controversial. The refrigerator standard issued for July 2001, for example, was promulgated through a series of compromises in December 1996, allowing a later enforcement date but at a higher efficiency level. Achieving similar consensus among disparate concerns such as the gas and electric industries and environmentalists may prove difficult, however, when multi-fuel products, such as water heaters, are considered for review. The debate over end-use efficiency versus total system efficiency is a lively one, with electric and gas concerns generally disagreeing as to how efficiency and environmental benefits should be measured. In fact, the inability to create a single national home energy rating system (HERS) has shown that achieving

Table 3. Effective dates of appliance efficiency standards, 1988-2005

Product	1988	1990	1992	1993	1994	1995	2000	2001	2005
Clothes dryers	X				X				
Clothes washers	X				X				
Dishwashers	X				X				
Refrigerators and freezers		X		X				X	
Kitchen ranges and ovens		X							
Room air conditioners		X					X		
Direct heating equipment		X							
Fluorescent lamp ballasts		X							X
Water heaters		X							
Pool heaters		X							
Central air conditioners and heat pumps			X						
Furnaces									
Central (>45,000 Btu per hour)			X						
Small (<45,000 Btu per hour)			X						
Mobile home		X							
Boilers			X						
Fluorescent lamps, 8 foot					X				
Fluorescent lamps, 2 and 4 foot (U tube)						X			

consensus among these groups is difficult, signaling a continued debate as to how efficiency should be evaluated across fuel types.

An agreement between manufacturers and energy efficiency advocates was reached in October 1999 on fluorescent lighting standards for commercial and industrial applications. The notice of the final rule for a fluorescent lamp ballast standard was published in the September 19, 2000, *Federal Register*, and the standard goes into effect in April 2005. It sets a minimum efficacy level for ballasts manufactured for T12 fluorescent lamps that effectively eliminates less efficient magnetic ballasts for those applications. Because the standard has been finalized, it is included for *AEO2001*.

Currently, DOE is in the process of evaluating new efficiency standards for several products. Proposed rules for water heaters, clothes washers, and central air conditioners and heat pumps have been published in the *Federal Register*, and final rules are expected in the coming months. After the final rules are published in the *Federal Register*, a lead time of 3 to 5 years is required for the standards to take effect. The next commercial sector products DOE intends to evaluate for standards include distribution transformers, commercial furnaces and boilers, commercial heat pumps and air conditioners, and commercial water heaters. Because the *AEO2001* reference case includes only standards that have been finalized, with the effective dates and efficiency levels specified in the *Federal Register*, these efficiency standards are not included in the projections.

Petroleum Reserves

After heating oil prices reached extreme highs in the Northeast in January-February 2000, DOE established a heating oil component of the Strategic Petroleum Reserve (SPR) in the Northeast. The heating oil reserve will provide up to 2 million barrels of emergency heating oil supplies. DOE obtained emergency stocks by exchanging crude oil from the SPR with companies that would provide heating oil and storage facilities. In addition to setting up an interim emergency heating oil supply, DOE proposed an amendment to the Strategic Petroleum Reserve Plan that would authorize heating oil storage on a permanent basis. A permanent Heating Oil Reserve was authorized in October 2000 with the passage of the Energy Act of 2000 (H.R. 2884).

In response to the tight supplies of oil and heating oil before the 2000-2001 winter heating season, President Clinton directed DOE to release 30 million barrels of crude oil from the SPR. DOE offered the crude oil reserves in exchange for crude oil to be returned to the SPR between August and November 2001. EIA estimates that the release of SPR crude oil will make available an additional 3 to 5 million barrels of distillate fuel in the market this winter.

Although the creation of the heating oil reserve and release of crude oil reserves are of interest to consumers in the Northeast, they have no impact on the *AEO2001* projections for petroleum, because the long-term annual projections in *AEO2001* do not reflect changes in stocks of crude oil or petroleum products.